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EXAMINER
JACOB, MARY C

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2123	

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Please find below and/or attached an Office communication concerning this application or proceeding.

The time period for reply, if any, is set in the attached communication.

Notice of the Office communication was sent electronically on above-indicated "Notification Date" to the following e-mail address(es):

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Office Action Summary	Application No.	Applicant(s)	
	10/575,030	JALALI ET AL.	
	Examiner	**Art Unit**	
	MARY C. JACOB	2123	

-- The MAILING DATE of this communication appears on the cover sheet with the correspondence address --

Period for Reply

A SHORTENED STATUTORY PERIOD FOR REPLY IS SET TO EXPIRE *3* MONTH(S) OR THIRTY (30) DAYS, WHICHEVER IS LONGER, FROM THE MAILING DATE OF THIS COMMUNICATION.

- Extensions of time may be available under the provisions of 37 CFR 1.136(a). In no event, however, may a reply be timely filed after SIX (6) MONTHS from the mailing date of this communication.
- If NO period for reply is specified above, the maximum statutory period will apply and will expire SIX (6) MONTHS from the mailing date of this communication.
- Failure to reply within the set or extended period for reply will, by statute, cause the application to become ABANDONED (35 U.S.C. § 133). Any reply received by the Office later than three months after the mailing date of this communication, even if timely filed, may reduce any earned patent term adjustment. See 37 CFR 1.704(b).

Status

1)☒ Responsive to communication(s) filed on *19 December 2006*.

2a)☐ This action is **FINAL**. 2b)☒ This action is non-final.

3)☐ Since this application is in condition for allowance except for formal matters, prosecution as to the merits is closed in accordance with the practice under *Ex parte Quayle*, 1935 C.D. 11, 453 O.G. 213.

Disposition of Claims

4)☒ Claim(s) *1-36* is/are pending in the application.

4a) Of the above claim(s) _____ is/are withdrawn from consideration.

5)☐ Claim(s) _____ is/are allowed.

6)☒ Claim(s) *1-36* is/are rejected.

7)☐ Claim(s) _____ is/are objected to.

8)☐ Claim(s) _____ are subject to restriction and/or election requirement.

Application Papers

9)☐ The specification is objected to by the Examiner.

10)☒ The drawing(s) filed on *07 April 2006* is/are: a)☒ accepted or b)☐ objected to by the Examiner.

Applicant may not request that any objection to the drawing(s) be held in abeyance. See 37 CFR 1.85(a).

Replacement drawing sheet(s) including the correction is required if the drawing(s) is objected to. See 37 CFR 1.121(d).

11)☐ The oath or declaration is objected to by the Examiner. Note the attached Office Action or form PTO-152.

Priority under 35 U.S.C. § 119

12)☐ Acknowledgment is made of a claim for foreign priority under 35 U.S.C. § 119(a)-(d) or (f).

a)☐ All b)☐ Some * c)☐ None of:

1.☐ Certified copies of the priority documents have been received.

2.☐ Certified copies of the priority documents have been received in Application No. _____.

3.☐ Copies of the certified copies of the priority documents have been received in this National Stage application from the International Bureau (PCT Rule 17.2(a)).

* See the attached detailed Office action for a list of the certified copies not received.

Attachment(s)

1) ☒ Notice of References Cited (PTO-892)

2) ☐ Notice of Draftsperson's Patent Drawing Review (PTO-948)

3) ☒ Information Disclosure Statement(s) (PTO/SB/08) Paper No(s)/Mail Date *20100204*.

4) ☐ Interview Summary (PTO-413) Paper No(s)/Mail Date. _____ .

5) ☐ Notice of Informal Patent Application

6) ☐ Other: _____.

DETAILED ACTION

1. Claims 1-36 have been presented for examination.

Claim Interpretation

2. Claims 1, 12 and 26 are directed to "methods". Though not expressly recited in the claims, the Examiner interprets these methods as being carried out by a computer based system (see paragraphs 0023 and 0024; Figure 4), and therefore, the methods are tied to another statutory category of invention.

Claim Rejections - 35 USC § 102

3. The following is a quotation of the appropriate paragraphs of 35 U.S.C. 102 that form the basis for the rejections under this section made in this Office action:

> A person shall be entitled to a patent unless –
>
> (e) the invention was described in (1) an application for patent, published under section 122(b), by another filed in the United States before the invention by the applicant for patent or (2) a patent granted on an application for patent by another filed in the United States before the invention by the applicant for patent, except that an international application filed under the treaty defined in section 351(a) shall have the effects for purposes of this subsection of an application filed in the United States only if the international application designated the United States and was published under Article 21(2) of such treaty in the English language.

4. **Claims 1-7, 12-15, 17-22, 25-32, 34-36** are rejected under 35 U.S.C. 102(e) as being anticipated by Shah et al (US Patent Application Publication 2004/0084180).

5. As to **Claim 1**, Shah et al teaches: <u>a method of determining production rates in a well</u> (paragraph 0005, "...methods and systems for estimating multi-phase fluid flow rates in a subterranean well..."; paragraph 0009, "...estimates multi-fluid flow rates are

provided for a plurality of selected well locations"), comprising: determining a model of temperature as a function of zonal flow rates in the well (paragraph 0025, lines 4-6, "It is well known that each of the entries 24 has its own fluid phase (whether it be oil, water or gas), flow rate, temperature and hydrocarbon mixture composition"; paragraph 0027, lines 1-14, "...the model 30 takes into account the conservation of energy and mass, and consequently simulates the evolution of the temperature of the flowing fluid...It is known that pressure and temperature of the flowing fluids change as they travel up or down a flow path...Therefore, model 30 should take such factors into consideration"; paragraph 0029, lines 8-11, "The user of the invention may specify...the temperature at each entry point 24 within the well 10"; paragraph 0036, lines 9-12, "In step 106, the mathematical model for the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations..."); measuring temperatures at a plurality of locations in the well (paragraph 0015; paragraph 0025, lines 16-24, "...a plurality of sensors 27 are deployed to take measurements at the various production zones 26 or other production points of interest inside the wellbore 12..."); and inverting the measured temperatures by applying the model to determine an allocation of production rates from different producing zones in the well (paragraph 0031, lines 1-4, "The data path 31 supplies transient data to the model, 30, such as...temperature data 43 measured at multiple downhole locations"; paragraph 0036, "Transient well data is measured...including pressure and temperature data in the wellbore 12 above each flow entry being produced...measurement above each flow entry is not required for the solution of the inverse problem...In step 106, the mathematical model of the wellbore 12

is run to calculate the expected pressure and temperature values at the downhole sensor locations, the expected volumetric phase flow rates at the wellhead 22, and sensitivity coefficients of the model response to each phase flow rate at each fluid entry location"; paragraph 0037, lines 4-10, "…the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations…"; paragraph 0038, "…the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary...In this way, the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"; claim 27, "…the multiphase fluid flow rate program further comprises a model inversion algorithm"; paragraph 0009, "…estimated multi-fluid flow rates are provided for a plurality of selected well locations").

6. As to **Claim 2**. Shah et al teaches: wherein determining comprises determining the model for a single-phase liquid producing well (paragraph 0026, lines 1-7).

7. As to **Claim 3**, Shah et al teaches: wherein determining comprises determining the model for a multi-layer producing well (Figure 1; paragraph 0025, lines 10-13).

8. As to **Claim 4**, Shah et al teaches: wherein determining comprises determining the model for a multi-layer, single-phase liquid producing well (Figure 1; paragraph 0025, lines 10-13; paragraph 0026, lines 1-7).

9. As to **Claim 5**, Shah et al teaches: wherein determining comprises determining the model for a multi-layer, multi-phase liquid producing well (Figure 1; paragraph 0025, lines 10-13; paragraph 0026, lines 1-7).

10. As to **Claim 6**, Shah et al teaches: wherein measuring comprises measuring temperature with a distributed temperature sensor (paragraph 0025, lines 16-24).

11. As to **Claim 7**, Shah et al teaches: wherein inverting comprises determining a degree of certainty in the production rates allocated (paragraph 0012; paragraph 0037, lines 9-12; paragraph 0038, lines 6-15).

12. As to **Claim 12**, Shah et al teaches: <u>a method of determining flow rates in a well</u> (paragraph 0005, "...methods and systems for estimating multi-phase fluid flow rates in a subterranean well..."; paragraph 0009, "...estimates multi-fluid flow rates are provided for a plurality of selected well locations"), <u>comprising: measuring temperature at a plurality of points along the well</u> (paragraph 0015; paragraph 0025, lines 16-24, "...a plurality of sensors 27 are deployed to take measurements at the various production zones 26 or other production points of interest inside the wellbore 12...") <u>having a plurality of well zones and a plurality of liquid phases</u> (Figure 1; paragraph 0025, lines 10-13; paragraph 0026, lines 1-7); <u>and determining flow rates of the plurality of liquid phases through each of the plurality of well zones</u> (Abstract, lines 7-10, "Multi-phase

fluid flow estimates may be obtained for the various liquid and gaseous fluids in the well (10) at multiple well locations (24)"; paragraph 0009, "...estimated multi-fluid flow rates are provided for a plurality of selected well locations"; paragraph 0036, lines 9-14, "…sensitivity coefficients of the model response to each phase flow rate at each fluid entry location…"; paragraph 0037, lines 1-4, "...the expected wellhead volumetric flow of each phase calculated in step 106 is compared with the measured volumetric phase flow rate obtained instep 104"; paragraph 0038, "…the modeling comparisons may be re-iterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...the final estimates of multiphase flow rates are provided...") <u>via the measured temperatures</u> (paragraph 0011, "…the method of estimating multi-phase fluid flow rates in a subterranean well...Steps are also provided for measuring the transient temperature, pressure and wellhead flow rate. The subterranean well is modeled using these measurements to estimate the multi-phase low rates in the subterranean well"; paragraph 0031, lines 1-4, "The data path 31 supplies transient data to the model, 30, such as...temperature data 43 measured at multiple downhole locations"; Figure 3, element 104-118 and description, paragraphs 0036-0038).

13. As to **Claim 13,** Shah et al teaches: wherein measuring comprises utilizing a distributed temperature sensor (paragraph 0025, lines 16-24).

14. As to **Claim 14,** Shah et al teaches: wherein determining comprises constructing a model of temperature as a function of zonal flow rates in the well (paragraph 0025, lines 4-6, "It is well known that each of the entries 24 has its own fluid phase (whether it

be oil, water or gas), flow rate, temperature and hydrocarbon mixture composition"; paragraph 0027, lines 1-14, "…the model 30 takes into account the conservation of energy and mass, and consequently simulates the evolution of the temperature of the flowing fluid…It is known that pressure and temperature of the flowing fluids change as they travel up or down a flow path…Therefore, model 30 should take such factors into consideration"; paragraph 0029, lines 8-11, "The user of the invention may specify…the temperature at each entry point 24 within the well 10"; paragraph 0036, lines 9-12, "In step 106, the mathematical model for the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations..."), and using the model to invert the measured temperatures in allocating flow rates from the plurality of well zones (paragraph 0031, lines 1-4, "The data path 31 supplies transient data to the model, 30, such as...temperature data 43 measured at multiple downhole locations"; paragraph 0036, "Transient well data is measured...including pressure and temperature data in the wellbore 12 above each flow entry being produced...measurement above each flow entry is not required for the solution of the inverse problem…In step 106, the mathematical model of the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations…"; paragraph 0037, lines 4-10, "…the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations…"; paragraph 0038, "…the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to

determine changes necessary...In this way, the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"; claim 27, "...the multiphase fluid flow rate program further comprises a model inversion algorithm"; paragraph 0009, "...estimated multi-fluid flow rates are provided for a plurality of selected well locations").

15. As to **Claim 15**, Shah et al teaches: wherein determining comprises determining flow rates of oil and water phases during production (Abstract, lines 7-10, "Multi-phase fluid flow estimates may be obtained for the various liquid and gaseous fluids in the well (10) at multiple well locations (24)"; paragraph 0009, "...estimated multi-fluid flow rates are provided for a plurality of selected well locations"; paragraph 0037, lines 1-4, "...the expected wellhead volumetric flow of each phase calculated in step 106 is compared with the measured volumetric phase flow rate obtained instep 104"; paragraph 0038, lines 11-15, "...if the measured volumetric phase rates...are intolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided..."; paragraph 0035, line 5; paragraph 0028, lines 1-4).

16. As to **Claim 17**, Shah et al teaches: wherein inverting the temperatures comprises utilizing an optimization algorithm (Figure 3 and description, paragraphs 0033-0038).

17. As to **Claim 18**, Shah et al teaches: wherein determining comprises measuring a total flow rate at a wellhead (paragraph 0011, lines 7-9; paragraph 0036, lines 8-9; Figure 3, step 104).

18. As to **Claim 19**, Shah et al teaches: <u>a system</u> (Figures 1, 2), <u>comprising: a temperature sensor deployable with a production completion along a wellbore to sense temperature data at a plurality of wellbore locations during production</u> (paragraph 0025, lines 16-24, "...a plurality of sensors 27 are deployed to take measurements at the various production zones 26 or other points of interest inside the wellbore 12. The sensors 27 are preferably downhole temperature and pressure transducers coupled to computer 32...may include fiber optic distributed temperature sensing ("DTS") systems..."); <u>and a processor system able to receive the temperature data and allocate a flow rate from a plurality of wellbore zones based on the temperature data</u> (paragraph 0025, lines 16-24, "The sensors 27 are preferably downhole temperature and pressure transducers coupled to computer 32..."; paragraph 0026, lines 5, "...the computer 32 incorporates the functionality of a mathematical model 30 designed to simulate the physical processes of the flow of multi-phase fluid...within the wellbore 12"; paragraph 0031, lines 1-4; paragraphs 0036-0038; paragraph 0009, "...estimated multi-fluid flow rates are provided for a plurality of selected well locations").

19. As to **Claim 20**, Shah et al teaches: wherein the processor system uses a temperature forward model, in which temperature is a function of zonal flow rates, to invert the temperature data and allocate flow rates from producing layers of a formation

(*model in which temperature is a function of zonal flow rates*: paragraph 0025, lines 4-6, “It is well known that each of the entries 24 has its own fluid phase (whether it be oil, water or gas), flow rate, temperature and hydrocarbon mixture composition”; paragraph 0027, lines 1-14, “…the model 30 takes into account the conservation of energy and mass, and consequently simulates the evolution of the temperature of the flowing fluid…It is known that pressure and temperature of the flowing fluids change as they travel up or down a flow path…Therefore, model 30 should take such factors into consideration”; paragraph 0029, lines 8-11, “The user of the invention may specify…the temperature at each entry point 24 within the well 10"; paragraph 0036, lines 9-12, "In step 106, the mathematical model for the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations..."; *temperature forward model/invert temperature data to allocate flow rates from producing layers of a formation*: paragraph 0031, lines 1-4, “The data path 31 supplies transient data to the model, 30, such as...temperature data 43 measured at multiple downhole locations"; paragraph 0036, "Transient well data is measured...including pressure and temperature data in the wellbore 12 above each flow entry being produced...measurement above each flow entry is not required for the solution of the inverse problem…In step 106, the mathematical model of the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations…”; paragraph 0037, lines 4-10, “…the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations…”;

paragraph 0038, "...the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary...In this way, the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"; claim 27, "...the multiphase fluid flow rate program further comprises a model inversion algorithm"; paragraph 0009, "...estimated multi-fluid flow rates are provided for a plurality of selected well locations").

20. As to **Claim 21**, Shah et al teaches: wherein the temperature sensor comprises a distributed temperature sensor (paragraph 0025, lines 16-24, "...a plurality of sensors 27 are deployed to take measurements at the various production zones 26 or other points of interest inside the wellbore 12. The sensors 27 are preferably downhole temperature and pressure transducers coupled to computer 32...may include fiber optic distributed temperature sensing ("DTS") systems...").

21. As to **Claim 22**, Shah et al teaches: wherein the processor system is able to allocate flow rates in a multi-layer, multi-phase liquid producing well (Figure 1; paragraph 0025, lines 10-13; paragraph 0026, lines 1-7).

22. As to **Claim 25**, Shah et al teaches: wherein the wellbore is oriented generally vertically (Figure 1; paragraph 0024, lines 11-15).

23. As to **Claim 26**, Shah et al teaches: a method, comprising: deploying a distributed temperature sensor along a wellbore (paragraph 0025, lines 16-24, "…a plurality of sensors 27 are deployed to take measurements at the various production zones 26 or other points of interest inside the wellbore 12. The sensors 27 are preferably downhole temperature and pressure transducers coupled to computer 32...may include fiber optic distributed temperature sensing ("DTS") systems..."); utilizing a model of temperature as a function of fluid flow rates into the wellbore (paragraph 0025, lines 4-6, "It is well known that each of the entries 24 has its own fluid phase (whether it be oil, water or gas), flow rate, temperature and hydrocarbon mixture composition"; paragraph 0027, lines 1-14, "…the model 30 takes into account the conservation of energy and mass, and consequently simulates the evolution of the temperature of the flowing fluid…It is known that pressure and temperature of the flowing fluids change as they travel up or down a flow path…Therefore, model 30 should take such factors into consideration"; paragraph 0029, lines 8-11, "The user of the invention may specify…the temperature at each entry point 24 within the well 10"; paragraph 0036, lines 9-12, "In step 106, the mathematical model for the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations..."); obtaining temperature data from the distributed temperature system (paragraph 0025, lines 16-24, "…a plurality of sensors 27 are deployed to take measurements at the various production zones 26 or other points of interest inside the wellbore 12. The sensors 27 are preferably downhole temperature and pressure

transducers coupled to computer 32…"; paragraph 0031, lines 1-4, "The data path 31 supplies transient data to the model 30, such as…temperature data 43…"Figure 3, element 104); allocating a fluid flow rate in at least one wellbore zone using the temperature data in conjunction with the model (paragraphs 0036-0038; paragraph 0009, "…estimated multi-fluid flow rates are provided for a plurality of selected well locations"); and determining error in the fluid flow rate (Figure 3, step 108 and description, paragraph 0037; paragraph 0038, lines 1-10, "...deviation between the calculated and measured quantities (of step 108)...").

24. As to **Claim 27**, Shah et al teaches: wherein allocating comprises inverting the temperature data to obtain the fluid flow rate (paragraph 0031, lines 1-4, "The data path 31 supplies transient data to the model, 30, such as...temperature data 43 measured at multiple downhole locations"; paragraph 0036, "Transient well data is measured...including pressure and temperature data in the wellbore 12 above each flow entry being produced...measurement above each flow entry is not required for the solution of the inverse problem…In step 106, the mathematical model of the wellbore 12 is run to calculate the expected pressure and temperature values at the downhole sensor locations…"; paragraph 0037, lines 4-10, "…the model-calculated expected pressure and temperature values for various well locations of step 106 are preferably compared with the measured temperature and pressure values obtained in step 104 with respect to those same well locations…"; paragraph 0038, "…the deviation between the calculated and measured quantities (of step 108) may be used with the sensitivity coefficients of the model (from step 106) to determine changes necessary...In this way,

the modeling comparisons may be reiterated...until an approximate match (within acceptable tolerances) is obtained between the calculated well properties and related flow rates and the measured well properties and flow rates...if the measured volumetric phase rates and pressure and temperature readings are in tolerable agreement with the expected values predicted by the model 30, the final estimates of the multiphase flow rates are provided as shown in step 118"; claim 27, "...the multiphase fluid flow rate program further comprises a model inversion algorithm").

25. As to **Claim 28**, Shah et al teaches: wherein deploying comprises deploying the distributed temperature system in a generally vertical wellbore (Figure 1, element 27; paragraph 0024, lines 11-15).

26. As to **Claim 29**, Shah et al teaches: wherein deploying comprises deploying the distributed temperature system in a deviated wellbore (Figure 1, element 27; paragraph 0024, lines 11-15).

27. As to **Claim 30**, Shah et al teaches: wherein allocating comprises determining fluid flow rates across a plurality of wellbore zones (paragraph 0009; paragraph 0036-0038).

28. As to **Claim 31**, Shah et al teaches: wherein allocating comprises determining flow rates for a single-phase liquid producing well (paragraph 0026, lines 1-7; paragraph 0025, line 5).

29. As to **Claim 32**, Shah et al teaches: wherein allocating comprises determining flow rates for a multi-phase liquid producing well (paragraph 0026, lines 1-7; paragraph

0025, line 5).

30. As to **Claim 34**, Shah et al teaches: a system (Figures 1 and 2), comprising: means for measuring temperature at a plurality of points along a well having a plurality of well zones and a plurality of liquid phases (Figure 1, elements 26, 27; paragraph 0025, lines 16-24; paragraph 0025, lines 1-6; paragraph 0026, lines 1-7); and means for determining flow rates of the plurality of liquid phases through each of the plurality of well zones via the measured temperatures (paragraph 0025, lines 16-21, "...The sensors 27 are preferably downhole temperature and pressure transducers coupled to a computer 32..."; paragraph 0026, lines 1-5, "...the computer 32 incorporates the functionality of a mathematical model 30 designed to simulate the physical processes of the flow of multi-phase fluid..."; Figure 3 and description, paragraphs 0033, 0036-0038; paragraph 0009).

31. As to **Claim 35**, Shah et al teaches: wherein the means for measuring comprises a distributed temperature sensor (paragraph 0025, lines 16-24).

32. As to **Claim 36**, Shah et al teaches: wherein the means for determining comprises a processor system able to receive the temperature data and allocate a flow rate from a plurality of wellbore zones based on the temperature data (Figure 2 and description; paragraph 0025, lines 19-21; paragraph 0026, lines 1-5, "...the computer 32 incorporates the functionality of a mathematical model 30 designed to simulate the physical processes of the flow of multi-phase fluid..."; Figure 3 and description,

paragraphs 0033, 0036-0038; paragraph 0009).

Claim Rejections - 35 USC § 103

33. The following is a quotation of 35 U.S.C. 103(a) which forms the basis for all obviousness rejections set forth in this Office action:

> (a) A patent may not be obtained though the invention is not identically disclosed or described as set forth in section 102 of this title, if the differences between the subject matter sought to be patented and the prior art are such that the subject matter as a whole would have been obvious at the time the invention was made to a person having ordinary skill in the art to which said subject matter pertains. Patentability shall not be negatived by the manner in which the invention was made.

This application currently names joint inventors. In considering patentability of the claims under 35 U.S.C. 103(a), the examiner presumes that the subject matter of the various claims was commonly owned at the time any inventions covered therein were made absent any evidence to the contrary. Applicant is advised of the obligation under 37 CFR 1.56 to point out the inventor and invention dates of each claim that was not commonly owned at the time a later invention was made in order for the examiner to consider the applicability of 35 U.S.C. 103(c) and potential 35 U.S.C. 102(e), (f) or (g) prior art under 35 U.S.C. 103(a).

34. **Claims 8-10 and 33** are rejected under 35 U.S.C. 103(a) as being unpatentable over Shah et al as applied to claims 1, 7 and 26 above, in view of Finsterle ("iTough2 User's Guide", Earth Sciences Division, Lawrence Berkley National Laboratory, University of California, May 2000).

35. Shah et al teaches a method of determining production rates in a well comprising inverting measured temperatures by applying a model of temperature as a function of zonal flow rates in a well to determine an allocation of production rates from different

producing zones in the well, wherein inverting comprises determining a degree of certainty in the production rates allocated, and allocating flow rate in at least one wellbore zone using temperature data in conjunction of the model and determining error in the fluid flow rate.

36. Shah et al does not expressly teach: (claim 8) wherein determining the degree of certainty comprises determining a degree of error in the model; (claim 9) wherein determining a degree of certainty comprises determining a degree of error in the measured temperatures; (claim 10) wherein determining the degree of certainty comprises determining a degree of error in well parameter values; (claim 33) wherein determining error in the fluid flow rate comprises compensating for model error, measurement error and well parameter error.

37. Finsterle teaches that in predicting multiphase fluid and heat flow in the subsurface by means of numerical simulation, errors in the conceptual model usually have the largest impact on model predictions, and assigning parameter values to the numerical model is likely to be tedious and challenging (page 2, paragraphs 1 and 2) and therefore teaches the iTOUGH2 computer program that provides inverse modeling capabilities for the TOUGH2 simulator (a numerical simulator for multidimensional, nonisothermal flows of multiphase, multicomponent fluids in porous and fractured media) that not only estimates model-related parameters by automatically calibrating TOUGH2 models to laboratory or field data, the information obtained by evaluating the sensitivity of the calculated system response with respect to certain input parameters can be used to study the appropriateness of a proposed experimental design and to

analyze the uncertainty of model predictions (page 4, paragraph 1). The iTOUGH2 program taught by Finsterle includes (**claim 8**) determining a degree of error in the model (page 4, section (2), "error analysis is performed"; page 7, item (4), "…Model output and measured data are compared only at discrete points in space and time, the so-called calibration points", equation 1.5.3 and description); (**claim 9**) determining a degree of error in the measurements (page 3, paragraph 2, lines 4-5; page 10, item 5; page 27, element 2.5.3.1); (**claim 10**) determining a degree of error in model parameter values (page 4, section (2), "error analysis is performed"; page 8, items 7 and 8, "objective function"); (**claim 33**) wherein determining error in the model output comprises compensating for model error, measurement error and model parameter error (page 6, items 8-9; page 8, items (8 and 9), "...find the minimum objecting function by iteratively updating the model parameters. Since the model output z(p) depends on the parameters to be estimated, the fit can be improved by changing the elements of parameter vector p…"; page 10, item 5 and page 11, equation 1.6.2 that shows the objective function to be minimized, S, includes measurement errors).

38. Shah et al and Finsterle are analogous art since they are both directed to modeling multiphase flows in a subsurface by means of inverse modeling.

39. It would have been obvious to one of ordinary skill in the art at the time the invention was made to modify the method of determining production rates in a well comprising inverting measured temperatures by applying a model of temperature as a function of zonal flow rates in a well to determine an allocation of production rates from different producing zones in the well, wherein inverting comprises determining a degree

of certainty in the production rates allocated, and allocating flow rate in at least one wellbore zone using temperature data in conjunction of the model and determining error in the fluid flow rate as taught by Shah et al to further include (claim 8) wherein determining the degree of certainty comprises determining a degree of error in the model; (claim 9) wherein determining a degree of certainty comprises determining a degree of error in the measurements (measured temperatures); (claim 10) wherein determining the degree of certainty comprises determining a degree of error in model (well) parameter values; (claim 33) wherein determining error in the fluid flow rate comprises compensating for model error, measurement error and well parameter error as taught by Finsterle since Finsterle teaches that in predicting multiphase fluid and heat flow in the subsurface by means of numerical simulation, errors in the conceptual model usually have the largest impact on model predictions, and assigning parameter values to the numerical model is likely to be tedious and challenging (page 2, paragraphs 1 and 2) and therefore teaches the iTOUGH2 computer program that provides inverse modeling capabilities for the TOUGH2 simulator (a numerical simulator for multidimensional, nonisothermal flows of multiphase, multicomponent fluids in porous and fractured media) that not only estimates model-related parameters by automatically calibrating TOUGH2 models to laboratory or field data, the information obtained by evaluating the sensitivity of the calculated system response with respect to certain input parameters can be used to study the appropriateness of a proposed experimental design and to analyze the uncertainty of model predictions (page 4, paragraph 1).

40. **Claim 11** is rejected under 35 U.S.C. 103(a) as being unpatentable over Shah et al as applied to claim 1 above, in view of Akin ("Analysis of Tracer Tests with Simple Spreadsheet Models", Computers and Geosciences, 27, pages 171-178, 2001).

41. Shah et al teaches a method of determining production rates in a well comprising inverting measured temperatures by applying a model of temperature as a function of zonal flow rates in a well to determine an allocation of production rates from different producing zones in the well, wherein the inverting comprises an optimization algorithm (Figure 3 and description, paragraphs 0033, 0036-0038).

42. Shah does not expressly teach wherein inverting comprises utilizing a generalized reduced gradient optimization algorithm.

43. Akin teaches a method of matching field data to predictions from computer simulation programs in tracer studies used for reservoir characterization that uses function evaluations rather than full simulator runs that results in a large reduction in computing time (Abstract, lines 4-7; section 1, paragraph 1, sentence 1; section 1, paragraph 2, lines 1-6 and lines 20-28), wherein after the reservoir models are implemented in a spreadsheet, the models were then matched to experimental data using the Generalized Reduced Gradient nonlinear optimization code to minimize the objective function (page 174, column 2, paragraph 4).

44. Shah et al and Akin are analogous art since they are both directed to modeling a reservoir using inverse modeling techniques that match the models to experimental data using optimization techniques that minimize an objective function.

45. It would have been obvious to one of ordinary skill in the art at the time the invention was made to modify the inversion technique comprising an optimization algorithm as taught by Shah to utilize a generalized reduced gradient optimization algorithm as taught by Akin since Akin teaches a method of matching field data to predictions from computer simulation programs in tracer studies used for reservoir characterization that uses function evaluations rather than full simulator runs that results in a large reduction in computing time (Abstract, lines 4-7; section 1, paragraph 1, sentence 1; section 1, paragraph 2, lines 1-6 and lines 20-28).

46. **Claim 16** is rejected under 35 U.S.C. 103(a) as being unpatentable over Shah as applied to claim 12 above, and further in view of Curtis (US Patent 3,913,398).

47. Shah et al teaches a method of determining flow rates in a well comprising determining flow rates of a plurality of liquid phases through each of a plurality of well zones via measured temperatures.

48. Shah et al does not expressly teach wherein determining comprises determining flow rates of fluid injected into each of the plurality of well zones.

49. Curtis teaches that temperature data has been useful in the studies of secondary recovery of crude petroleum and that in the secondary recovery of crude petroleum, it is important not only to locate each permeable formation accepting fluid but also to determine the flow rates at which the fluid enters each formation (column 1, lines 24-33) and teaches that determining flow rates of fluid injected into a plurality of well zones

using temperature data is well known in the art (column 1, lines 34-50; column 2, lines 27-41).

50. Shah et al and Curtis are analogous art since they are both directed to determining flow rates of fluids (such as oil) produced in wells at each of a plurality of possible entry points through the use of temperature data.

51. It would have been obvious to one of ordinary skill in the art at the time the invention was made to modify the method of determining flow rates in a well comprising determining flow rates of a plurality of liquid phases through each of a plurality of well zones via measured temperatures as taught by Shah to further include determining flow rates of fluid injected into each of the plurality of well zones as taught by Curtis since Curtis teaches that temperature data has been useful in the studies of secondary recovery of crude petroleum and that in the secondary recovery of crude petroleum, it is important not only to locate each permeable formation accepting fluid but also to determine the flow rates at which the fluid enters each formation (column 1, lines 26-33) and teaches that determining flow rates of fluid injected into a plurality of well zones using temperature data is well known in the art (column 1, lines 34-50; column 2, lines 27-41).

52. **Claims 23 and 24** are rejected under 35 U.S.C. 103(a) as being unpatentable over Shah as applied to claim 19 above, in view of Tubel (US Patent 6,082,454).

53. Shah et al teaches a system comprising a production completion in a wellbore (Figure 1, elements 14, 16, 18, 20, 22, 24, 28).

54. Shah does not expressly teach that the production completion (claim 23) comprises an electric submersible pumping system or (claim 24) a gas lift system.

55. Tubel teaches spooled coiled tubing strings (production/completion strings) which include desired devices and sensors that are assembled and tested at the factory prior to the deployment of the string such that it substantially increases the quality and reliability of such strings and reduces the deployment or retrieval time (column 2, lines 7-21), wherein a production completion according to the invention comprises devices typically used with a production completion such as an electrical submersible pump and/or a gas lift device according to the particular application (column 5, lines 29-36).

56. Shah and Tubel are analogous art since they are both directed to production completions deployed in a wellbore.

57. It would have been obvious to one of ordinary skill in the art at the time the invention was made to modify the production completion as taught by Shah to further include an electric submersible pumping system and a gas lift system as taught by Tubel since Tubel teaches spooled coiled tubing strings (production/completion strings) which include desired devices and sensors that are assembled and tested at the factory prior to the deployment of the string such that it substantially increases the quality and reliability of such strings and reduces the deployment or retrieval time (column 2, lines 7-21), wherein the devices include an electrical submersible pump and/or a gas lift device among others that are used with the production string according to the particular application (column 5, lines 29-36).

Conclusion

58. The prior art made of record and not relied upon is considered pertinent to applicant's disclosure.

59. Brown (US Patent 6,920,395) teaches a fiber optic sensor system that provides sufficient thermal data to determine the mass flow rates of produced fluids within a wellbore.

60. Coblentz et al (US Patent 4,520,666) teaches a method and apparatus for determining the flow rate of a fluid in a well using temperature data.

61. Samaroo (US Patent 5,960,369) teaches an apparatus and method for determining the characteristics of a multi-phase fluid along a well hole having a predefined geometric profile.

62. Sakaguchi et al ("Temperature Logging by the Distributed Temperature Sensing Technique During Injection Tests", Proceedings, World Geothermal Conference, May 28-June 10, 2000) reports results of field measurements taken during cold water injection tests in three geothermal wells and teaches advantages of the DTS temperature logging system.

63. Any inquiry concerning this communication or earlier communications from the examiner should be directed to Mary C. Jacob whose telephone number is 571-272-6249. The examiner can normally be reached on Tuesday-Thursday, 7AM-4PM.

If attempts to reach the examiner by telephone are unsuccessful, the examiner's supervisor, Paul Rodriguez can be reached on 571-272-3753. The fax phone number for the organization where this application or proceeding is assigned is 571-273-8300.

Information regarding the status of an application may be obtained from the Patent Application Information Retrieval (PAIR) system. Status information for published applications may be obtained from either Private PAIR or Public PAIR. Status information for unpublished applications is available through Private PAIR only. For more information about the PAIR system, see http://pair-direct.uspto.gov. Should you have questions on access to the Private PAIR system, contact the Electronic Business Center (EBC) at 866-217-9197 (toll-free).

/Mary C Jacob/

Examiner, Art Unit 2123

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